Enable Midstream Partners, LP
Form 10-Q
May 02, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

ENABLE MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	72-1252419
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Leadership Square
211 North Robinson Avenue
Suite 150
Oklahoma City, Oklahoma 73102
(Address of principal executive offices)
(Zip Code)

(405) 525-7788
Registrant's telephone number, including area code

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes þ No

As of April 13, 2018, there were 433,074,409 common units outstanding.

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AVAILABLE INFORMATION

Our website is www.enablemidstream.com. On the investor relations tab of our website, http://investors.enablemidstream.com, we make available free of charge a variety of information to investors. Our goal is to maintain the investor relations tab of our website as a portal through which investors can easily find or navigate to pertinent information about us, including but not limited to:

- our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file that material with or furnish it to the SEC;
- press releases on quarterly distributions, quarterly earnings, and other developments;
- governance information, including our governance guidelines, committee charters, and code of ethics and business conduct;
- information on events and presentations, including an archive of available calls, webcasts, and presentations;
- news and other announcements that we may post from time to time that investors may find useful or interesting; and
- opportunities to sign up for email alerts and RSS feeds to have information pushed in real time.

Information contained on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

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GLOSSARY OF TERMS

2015 Term Loan Agreement.	$450 million unsecured term loan agreement.
2019 Notes.	$500 million aggregate principal amount of the Partnership's 2.400% senior notes due 2019.
2024 Notes.	$600 million aggregate principal amount of the Partnership's 3.900% senior notes due 2024.
2027 Notes.	$700 million aggregate principal amount of the Partnership's 4.400% senior notes due 2027.
2044 Notes.	$550 million aggregate principal amount of the Partnership's 5.000% senior notes due 2044.
Adjusted EBITDA.	A non-GAAP measure calculated as net income attributable to limited partners plus depreciation and amortization expense, interest expense, net of interest income, income tax expense, distributions received from equity method affiliate in excess of equity earnings, non-cash equity-based compensation, changes in fair value of derivatives, certain other non-cash gains and losses (including gains and losses on sales of assets and write-downs of materials and supplies) and impairments, less the noncontrolling interest allocable to Adjusted EBITDA.
Adjusted interest expense.	A non-GAAP measure calculated as interest expense plus amortization of premium on long-term debt and capitalized interest on expansion capital, less amortization of debt costs and discount on long-term debt.
Annual Report.	Annual Report on Form 10-K for the year ended December 31, 2017.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASC.	Accounting Standards Codification.
ASU.	Accounting Standards Update.
ATM Program.	The offer and sale, from time to time, of common units representing limited partner interest having an aggregate offering price of up to $200 million in quantities, by sales methods and at prices determined by market conditions and other factors at the time of such sales, pursuant to that certain ATM Equity Offering Sales Agreement, entered into on May 12, 2017.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf/d.	Billion cubic feet per day.
Btu.	British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	A non-GAAP measure calculated as Adjusted EBITDA, as further adjusted for Series A Preferred Unit distributions, distributions for phantom and performance units, Adjusted interest expense, maintenance capital expenditures and current income taxes.
Distribution coverage ratio.	A non-GAAP measure calculated as DCF divided by distributions related to common and subordinated unitholders.
DRIP.	Distribution Reinvestment Plan entered into on June 23, 2016, which offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units.
EGT.	

	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates an approximately 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex Basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates an approximately 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
EOIT Senior Notes.	\$250 million 6.25% senior notes due 2020.
Exchange Act.	Securities Exchange Act of 1934, as amended.

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FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
Gross margin.	A non-GAAP measure calculated as Total revenues minus Cost of natural gas and natural gas liquids, excluding depreciation and amortization.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
LIBOR.	London Interbank Offered Rate.
MBbl.	Thousand barrels.
MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013.
MMcf.	Million cubic feet of natural gas.
MMcf/d.	Million cubic feet per day.
MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,600-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
Partnership.	Enable Midstream Partners, LP, and its subsidiaries.
Partnership Agreement.	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of November 14, 2017.
Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility.
SEC.	Securities and Exchange Commission.
Second Amended and Restated Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility entered into on April 6, 2018, which amended and restated the Revolving Credit Facility.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
WTI.	West Texas Intermediate.

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FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “could,” “will,” “should,” “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “p “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-loo statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report and in our Annual Report. Those risk factors and other factors noted throughout this report and in our Annual Report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the supply and demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- strategic decisions by CenterPoint Energy and OGE Energy regarding their ownership of us and Enable GP;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers’ obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of future litigation; and
- other factors set forth in this report and our other filings with the SEC, including our Annual Report.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
	(In millions, except per unit data)	
Revenues (including revenues from affiliates (Note 12)):		
Product sales	$443	$386
Service revenues	305	280
Total Revenues	748	666
Cost and Expenses (including expenses from affiliates (Note 12)):		
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	375	308
Operation and maintenance	94	89
General and administrative	27	25
Depreciation and amortization	96	88
Taxes other than income tax	17	16
Total Cost and Expenses	609	526
Operating Income	139	140
Other Income (Expense):		
Interest expense	(33)	(27)
Equity in earnings of equity method affiliate	6	7
Other, net	2	1
Total Other Expense	(25)	(19)
Income Before Income Tax	114	121
Income tax expense	—	1
Net Income	$114	$120
Less: Net income attributable to noncontrolling interest	—	—
Net Income Attributable to Limited Partners	$114	$120
Less: Series A Preferred Unit distributions (Note 6)	9	9
Net Income Attributable to Common and Subordinated Units (Note 5)	$105	$111
Basic earnings per unit (Note 5)		
Common units	$0.24	$0.26
Subordinated units	$—	$0.25
Diluted earnings per unit (Note 5)		
Common units	$0.24	$0.26
Subordinated units	$—	$0.25

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2018	December 31, 2017
	(In millions)	
Current Assets:		
Cash and cash equivalents	$30	$ 5
Restricted cash	14	14
Accounts receivable, net of allowance for doubtful accounts	253	277
Accounts receivable—affiliated companies	19	18
Inventory	39	40
Gas imbalances	35	37
Other current assets	23	25
Total current assets	413	416
Property, Plant and Equipment:		
Property, plant and equipment	12,273	12,079
Less accumulated depreciation and amortization	1,805	1,724
Property, plant and equipment, net	10,468	10,355
Other Assets:		
Intangible assets, net	440	451
Goodwill	12	12
Investment in equity method affiliate	317	324
Other	37	35
Total other assets	806	822
Total Assets	$11,687	$ 11,593
Current Liabilities:		
Accounts payable	$209	$ 263
Accounts payable—affiliated companies	5	3
Current portion of long-term debt	450	450
Short-term debt	595	405
Taxes accrued	26	32
Gas imbalances	8	12
Other	111	114
Total current liabilities	1,404	1,279
Other Liabilities:		
Accumulated deferred income taxes, net	6	6
Regulatory liabilities	21	21
Other	43	38
Total other liabilities	70	65
Long-Term Debt	2,594	2,595
Commitments and Contingencies (Note 13)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at March 31, 2018 and December 31, 2017)	362	362
Common units (433,072,001 issued and outstanding at March 31, 2018 and 432,584,080 issued and outstanding at December 31, 2017, respectively)	7,246	7,280
Noncontrolling interest	11	12

Total Partners’ Equity	7,619	7,654
Total Liabilities and Partners’ Equity	$11,687	$ 11,593

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$114	$120
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	96	88
Deferred income taxes	—	1
Loss on sale/retirement of assets	1	1
Equity in earnings of equity method affiliate	(6)	(7)
Return on investment in equity method affiliate	6	7
Equity-based compensation	5	4
Amortization of debt costs and discount (premium)	—	(1)
Changes in other assets and liabilities:		
Accounts receivable, net	24	18
Accounts receivable—affiliated companies	(1)	(8)
Inventory	1	1
Gas imbalance assets	2	17
Other current assets	(4)	1
Other assets	(3)	2
Accounts payable	(62)	(55)
Accounts payable—affiliated companies	2	—
Gas imbalance liabilities	(4)	(17)
Other current liabilities	(6)	(16)
Other liabilities	1	—
Net cash provided by operating activities	166	156
Cash Flows from Investing Activities:		
Capital expenditures	(190)	(61)
Proceeds from sale of assets	7	1
Return of investment in equity method affiliate	7	4
Net cash used in investing activities	(176)	(56)
Cash Flows from Financing Activities:		
Proceeds from long term debt, net of issuance costs	—	691
Proceeds from revolving credit facility	—	264
Repayment of revolving credit facility	—	(900)
Increase in short-term debt	190	—
Distributions	(150)	(147)
Cash taxes paid for employee equity-based compensation	(5)	—
Net cash provided by (used in) financing activities	35	(92)
Net Increase in Cash, Cash Equivalents and Restricted Cash	25	8
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	19	23
Cash, Cash Equivalents and Restricted Cash at End of Period	$44	$31

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(Unaudited)

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2016	15	$362	224	$3,737	208	$3,683	$ 12	$7,794
Net income	—	9	—	58	—	53	—	120
Distributions	—	(9)	—	(72)	—	(66)	—	(147)
Equity-based compensation, net of units for employee taxes	—	—	—	4	—	—	—	4
Balance as of March 31, 2017	15	$362	224	$3,727	208	$3,670	$ 12	$7,771
Balance as of December 31, 2017	15	$362	433	$7,280	—	$—	$ 12	$7,654
Net income	—	9	—	105	—	—	—	114
Distributions	—	(9)	—	(139)	—	—	(1)	(149)
Equity-based compensation, net of units for employee taxes	—	—	—	—	—	—	—	—
Balance as of March 31, 2018	15	$362	433	$7,246	—	$—	$ 11	$7,619

See Notes to the Unaudited Condensed Consolidated Financial Statements
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ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, OGE Energy and ArcLight. The Partnership’s assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership’s natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership’s natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, an interstate pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership’s Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

As of March 31, 2018, CenterPoint Energy held approximately 54.0% or 233,856,623 of the Partnership’s common units, and OGE Energy held approximately 25.6% or 110,982,805 of the Partnership’s common units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 6 for further information related to the Series A Preferred Units. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership’s general partner on an annual or continuing basis and may not remove Enable GP, its current general partner, without at least a 75% vote by all unitholders, including all units held by the Partnership’s limited partners, and Enable GP and its affiliates, voting together as a single class.

As of March 31, 2018, the Partnership owned a 50% interest in SESH. See Note 7 for further discussion of SESH.

Basis of Presentation

The accompanying condensed consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with GAAP have been omitted. The accompanying condensed consolidated financial statements and related notes should be read in conjunction with the consolidated financial statements and related notes included in our Annual Report.

The condensed consolidated financial statements and the related notes reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. Amounts reported in the Partnership’s Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Partnership’s reportable segments, see Note 15.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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Restricted Cash

Restricted cash primarily consists of cash collateral which is provided as credit assurance by third parties. The Condensed Consolidated Balance Sheets have $14 million of restricted cash at each of March 31, 2018 and December 31, 2017.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, management evaluates our customers' financial strength based on aging of accounts receivable, payment history, and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $2 million allowance for doubtful accounts was required at March 31, 2018 and a $3 million allowance at December 31, 2017.

Inventory

Natural gas inventory is held, through the transportation and storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or net realizable value. The Partnership recorded a $3 million and zero lower of cost or net realizable value adjustment in the three months ended March 31, 2018 and 2017, respectively.

Income Taxes

The Partnership's earnings are not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Leases

In February 2016, the FASB issued ASU 2016-02, “Leases (ASC 842).” This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

In January 2018, the FASB issued ASU 2018-01, “Land Easement Practical Expedient for Transition to Topic 842.” This standard permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Partnership's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. The Partnership intends to elect this transition provision.

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The Partnership continues to review contracts and easements relative to the provisions of the ASU 2016-02 lease standard and the ASU 2018-01 easement standard as well as to monitor relevant emerging industry guidance regarding the implementation of the standards. The Partnership expects to adopt these standards in the first quarter of 2019 and is currently evaluating the overall impact of the standards on our Condensed Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

(3) Revenue

The Partnership adopted ASU No. 2014-09, "Revenue from Contracts with Customers" (ASC 606) on January 1, 2018 using the modified retrospective method. Upon adoption, the Partnership did not recognize a material cumulative adjustment to Partners' Equity and there were no material changes in the timing of revenue recognition or our accounting policies. The Partnership has applied the standard to only contracts that were not expired as of January 1, 2018.

The following table disaggregates total revenues by major source from contracts with customers and the change in fair value of derivatives.

	Three Months Ended March 31, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$106	$ 131	$ (109)	$128
Natural gas liquids	279	7	(7)	279
Condensate	36	—	—	36
Total revenues from natural gas, natural gas liquids, and condensate	421	138	(116)	443
Gain (loss) on derivative activity	(3)	2	1	—
Total Product sales	$418	$ 140	$ (115)	$443
Service revenues:				
Demand revenues	$50	$ 120	$ —	$170
Volume-dependent revenues	123	19	(7)	135
Total Service revenues	$173	$ 139	$ (7)	$305
Total Revenues	$591	$ 279	$ (122)	$748

Product Sales

Natural Gas, NGLs or Condensate

We deliver natural gas, NGLs and condensate to purchasers at contractually agreed-upon delivery points at which the purchaser takes custody, title, and risk of loss of the commodity. We recognize revenue when control transfers to the purchaser at the delivery point based on the contractually agreed upon fixed or index based price received.

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Gain (loss) on Derivative Activity

Included in Product sales are gains and losses on natural gas, natural gas liquids, and crude oil (for condensate) derivatives that are accounted for under guidance in ASC 815. See Note 9 for further discussion of our derivative and hedging activity.

Service Revenues

Demand revenues

Our demand revenue arrangements are generally structured in one of the following ways:

- Under a firm fee arrangement, a customer agrees to pay a fixed fee for a contractually agreed upon pipeline or storage capacity. Once the services have been completed, or the customer no longer has access to the contracted capacity, revenue is recognized.
- Under a minimum volume commitment fee arrangement, a customer agrees to either deliver a contractually agreed upon minimum volume of natural gas or crude oil to our system for service at a contractually agreed upon gathering fee or to pay the contractually agreed upon gathering, compressing and treating fees for the minimum volume of natural gas or crude oil irrespective of whether or not the minimum volume of natural gas or crude oil is delivered. Certain of our contracts provide our customers the option to elect to pay a higher gathering fee over the remaining term of the contract in lieu of making a contractually agreed upon shortfall payment. Once the services have been completed, or the customer no longer has the ability to utilize the services, revenue is recognized.

Volume-dependent revenues

Our volume-dependent revenues primarily consist of gathering, compressing, treating, processing, transportation or storage services fees on contracts that exceed their contractually committed volume or do not have firm fee arrangements or minimum volume commitments. These fees are dependent on throughput by third party customers, and revenue is recognized over time as the service is performed. Our other fee revenue arrangements have pricing terms that are generally structured in one of the following ways: (1) Contractually agreed upon monetary fee for service or (2) contractually agreed upon consideration received in the form of natural gas or natural gas liquids, which are valued at the current month index based price, which approximates fair value.

Accounts Receivable

Payments for all types of revenues are typically received within 30 days of invoice. Invoices for all revenue types are sent on at least a monthly basis, except for the shortfall provisions under certain minimum volume commitment contracts, which are typically invoiced annually. Accounts receivable includes accrued revenues associated with certain minimum volume commitments that will be invoiced at the conclusion of the measurement period specified under the respective contracts.

	March 31, 2018	December 31, 2017
	(In millions)	
Accounts Receivable:		
Customers	$233	$ 265
Accrued minimum volume commitments (contract assets)	34	27
Non-customers	5	3
Total Accounts Receivable [(1)]	$272	$ 295

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(1)Total Accounts Receivable includes Accounts receivables, net of allowance for doubtful accounts and Accounts receivable—affiliated companies.

Contract Liabilities

Our contract liabilities primarily consist of the following prepayments received from customers:

- Under certain firm fee arrangements, customers pay their demand fee prior to the month of contracted capacity. These fees are applied to the subsequent month's activity and are included in other liabilities on the Condensed Consolidated Balance Sheets.

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- Under certain demand and volume dependent arrangements, customers make contributions of aid in construction payments. For payments that are related to contracts under ASC 606, the payment is deferred and amortized over the life of the associated contract and the unamortized balance is included in other current or long-term liabilities on the Condensed Consolidated Balance Sheets.

The table below summarizes the change in the contract liabilities for the three months ended March 31, 2018:

	March 31, 2018	December 31, 2017	Amounts recognized in revenues
	(In millions)		
Deferred revenues	$41	$ 34	$ 15

The table below summarizes the timing of recognition of these contract liabilities as of March 31, 2018:

	2018	2019	2020	2021	2022 and After
	(In millions)				
Deferred revenues	$19	$ 4	$ 4	$ 4	$ 10

Remaining Performance Obligations

Our remaining performance obligations consist primarily of firm fee and minimum volume commitment fee arrangements. Upon completion of the performance obligations associated with these arrangements, customers are invoiced and revenue is recognized as Service revenues in the Condensed Consolidated Statements of Income.

The table below summarizes the timing of recognition of the remaining performance obligations as of March 31, 2018:

	2018	2019	2020	2021	2022 and After
Transportation and Storage	$325	$329	$244	$123	$608
Gathering and Processing	175	221	118	94	328
Total remaining performance obligations	$500	$550	$362	$217	$936

Impact of Adoption

Upon adoption of ASC 606, the recognition of revenues for certain contractual arrangements was impacted as follows:

- Natural gas and natural gas liquids purchase arrangements - For certain arrangements within our gathering and processing segment, the Partnership purchases and controls the entire hydrocarbon stream at the point of receipt. As of January 1, 2018, these arrangements are considered supplier contracts rather than contracts with customers. Therefore, beginning January 1, 2018, the gathering and processing fees for these arrangements that were previously recognized as Service revenues under ASC 605 are recognized as reductions to Cost of natural gas and natural gas liquids.
- Percent-of-proceeds and percent-of-liquids processing arrangements - Under percent-of-proceeds and percent-of-liquids arrangements within our gathering and processing segment, the Partnership has previously recognized the value of natural gas and natural gas liquids received in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the natural gas and NGLs received as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the natural gas or NGLs are sold and Product sales are recognized.
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Keep-whole arrangements - Under keep-whole arrangements within our gathering and processing segment, the Partnership has previously recognized the value of NGLs received in Product sales and the value of the thermally equivalent quantity of natural gas provided in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the NGLs received less the value of the thermal equivalent volume of natural gas provided as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the NGLs are sold and Product sales are recognized.

- Fixed fuel arrangements - Under certain gathering arrangements within our gathering and processing segment as well as under certain transportation arrangements within our transportation and storage segment we receive a fixed amount of fuel regardless of actual fuel usage. Previously, revenue for fuel in excess of actual usage was recognized

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when such fuel was received, and additional revenue was recognized when such fuel was sold. As of January 1, 2018, fuel in excess of actual usage is treated as a byproduct obtained through the fulfillment of a contract, and the Partnership will recognize revenue at the time the excess fuel is sold. This results in a reduction of Product sales and a corresponding reduction in Cost of natural gas and natural gas liquids.

- Natural gas and natural gas liquids sales arrangements - For certain arrangements within our gathering and processing segment, the Partnership sells the entire hydrocarbon stream at the point of delivery to a third-party processing facility. As of January 1, 2018, these arrangements are considered sales once control has transferred to the third-party processing facility. Therefore, beginning January 1, 2018, the transportation and fractionation fees for these arrangements that were previously recognized as a component of cost of gas and natural gas liquids, are recognized as reductions to the transaction price under ASC 606.

Below is a summary of the impact of the changes on revenues as it relates to the three months ended March 31, 2018:

	Three Months Ended March 31, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
	(In millions)		
Revenues:			
Product sales:			
Natural gas	$128	$139	$ (11)
Natural gas liquids	279	283	(4)
Condensate	36	36	—
Total revenues from natural gas, natural gas liquids, and condensate	443	458	(15)
Gain (loss) on derivative activity	—	—	—
Total Product sales	$443	$458	$ (15)
Service revenues:			
Demand revenues	$170	$170	—
Volume-dependent revenues	135	134	1
Total Service revenues	$305	$304	$ 1
Total Revenues	$748	$762	$ (14)

As described above, each of the identified increases/(decreases) in revenue resulted in a corresponding change in the Cost of natural gas and natural gas liquids.

(4) Acquisition

Align Acquisition

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, a midstream service provider with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $298 million in cash. The acquisition includes approximately 190 miles of natural gas gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana and a cryogenic natural gas processing plant in Panola County, Texas, with a capacity of 100 MMcf/d. The acquisition was accounted for as a business combination and funded with borrowings under the Revolving Credit Facility. During the fourth quarter of 2017, the Partnership finalized the purchase price allocation as of October 4, 2017.

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The following table presents the fair value of the identified assets acquired and liabilities assumed at the acquisition date:

Purchase price allocation (in millions):	
Assets acquired:	
Accounts receivable	$5
Property, plant and equipment	111
Intangibles	176
Goodwill	12
Liabilities assumed:	
Current liabilities	6
Total identifiable net assets	$298

In connection with the acquisition, the Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 10 years. Goodwill recognized from the acquisition primarily relates to greater operating leverage in the Ark-La-Tex Basin and is allocated to the gathering and processing segment. The Partnership incurred approximately $2 million of acquisition costs associated with this transaction, which were included in General and administrative expense in the Consolidated Statements of Income in the fourth quarter of 2017. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

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(5) Earnings Per Limited Partner Unit

The following table illustrates the Partnership's calculation of earnings per unit for common and subordinated units:

	Three Months Ended March 31,	
	2018	2017
	(In millions, except per unit data)	
Net income	$114	$120
Net income attributable to noncontrolling interest	—	—
Series A Preferred Unit distributions	9	9
General partner interest in net income	—	—
Net income available to common and subordinated unitholders	$105	$111
Net income allocable to common units	$105	$58
Net income allocable to subordinated units	—	53
Net income available to common and subordinated unitholders	$105	$111
Net income allocable to common units	$105	$58
Dilutive effect of Series A Preferred Unit distributions	—	—
Diluted net income allocable to common units	105	58
Diluted net income allocable to subordinated units	—	53
Total	$105	$111
Basic weighted average number of outstanding		
Common units [(1)]	434	225
Subordinated units	—	208
Total	434	433
Basic earnings per unit		
Common units	$0.24	$0.26
Subordinated units	$—	$0.25
Basic weighted average number of outstanding common units	434	225
Dilutive effect of Series A Preferred Units	—	—
Dilutive effect of performance units	1	1
Diluted weighted average number of outstanding common units	435	226
Diluted weighted average number of outstanding subordinated units	—	208
Total	435	434
Diluted earnings per unit		
Common units	$0.24	$0.26
Subordinated units	$—	$0.25

(1) Basic weighted average number of outstanding common units for each of the three months ended March 31, 2018 and 2017 includes approximately one million time-based phantom units.

See Note 6 for discussion of the expiration of the subordination period.

The dilutive effect of the unit-based awards discussed in Note 14 was less than $0.01 per unit during each of the three months ended March 31, 2018 and 2017.

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(6) Partners’ Equity

The Partnership Agreement requires that, within 60 days after the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders, as applicable, during 2017 and 2018 (in millions, except for per unit amounts):

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
March 31, 2018[(1)]	May 22, 2018	May 29, 2018	$ 0.318	$ 138
December 31, 2017	February 20, 2018	February 27, 2018	$ 0.318	$ 138
September 30, 2017	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137
December 31, 2016	February 21, 2017	February 28, 2017	$ 0.318	$ 137

(1) The board of directors of Enable GP declared this 0.318 per common unit cash distribution on May 1, 2018, to be paid on May 29, 2018, to common unitholders of record at the close of business on May 22, 2018.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2017 and 2018 (in millions, except for per unit amounts):

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
March 31, 2018[(1)]	May 1, 2018	May 15, 2018	$ 0.625	$ 9
December 31, 2017	February 9, 2018	February 15, 2018	$ 0.625	$ 9
September 30, 2017	October 31, 2017	November 14, 2017	$ 0.625	$ 9
June 30, 2017	July 31, 2017	August 14, 2017	$ 0.625	$ 9
March 31, 2017	May 2, 2017	May 12, 2017	$ 0.625	$ 9
December 31, 2016	February 10, 2017	February 15, 2017	$ 0.625	$ 9

(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on May 1, 2018, to be paid on May 15, 2018, to Series A Preferred unitholders of record at the close of business on May 1, 2018.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units that they own.

Expiration of Subordination Period

The financial tests required for conversion of all subordinated units were met and the 207,855,430 outstanding subordinated units were converted into common units on a one-for-one basis on August 30, 2017. The conversion of the subordinated units did not change the aggregate amount of outstanding units, and the conversion of the subordinated units did not impact the amount of cash available for distribution by the Partnership.

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Series A Preferred Units

On February 18, 2016, the Partnership completed a private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership's common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

If and when declared by our general partner, holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis equal to subject to certain adjustments, an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement, pursuant to which the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. During the three months ended March 31, 2018, the Partnership did not issue any common units under the ATM Program.

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(7) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

SESH is owned 50% by Spectra Energy Partners, LP and 50% by the Partnership. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP may, under certain circumstances, have the right to purchase the Partnership's interest in SESH at fair market value, subject to certain exceptions.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. The Partnership billed SESH $2 million and $5 million during the three months ended March 31, 2018 and 2017, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Condensed Consolidated Statements of Income for the three months ended March 31, 2018 and 2017.

Equity in Earnings of Equity Method Affiliate:

	Three Months Ended March 31, 2018	2017
	(In millions)	
SESH	$ 6	$ 7

Distributions from Equity Method Affiliate:

	Three Months Ended March 31, 2018	2017
	(In millions)	
SESH [(1)]	$ 13	$ 11

(1) Distributions from equity method affiliate includes a $6 million and $7 million return on investment and a $7 million and $4 million return of investment for the three months ended March 31, 2018 and 2017, respectively.

Summarized financial information of SESH:

	Three Months Ended March 31, 2018	2017

	(In millions)	
Income Statements:		
Revenues	$ 28	$ 28
Operating income	$ 17	$ 17
Net income	$ 12	$ 13

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(8) Debt

The following table presents the Partnership's outstanding debt as of March 31, 2018 and December 31, 2017.

	March 31, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Total Debt	Outstanding Principal	Premium (Discount)	Total Debt
	(In millions)					
Commercial Paper	$596	$ (1)	$595	$405	$ —	$405
Revolving Credit Facility	—	—	—	—	—	—
2015 Term Loan Agreement	450	—	450	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	—	600
2027 Notes	700	(3)	697	700	(3)	697
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	11	261	250	13	263
Total debt	$3,646	$ 7	$3,653	$3,455	$ 10	$3,465
Less: Current portion of long-term debt			450			450
Less: Short-term debt (1)			595			405
Less: Unamortized debt expense (2)			14			15
Total long-term debt			$2,594			$2,595

(1) Short-term debt includes $596 million and $405 million of outstanding commercial paper as of March 31, 2018 and December 31, 2017, respectively.

(2) As of March 31, 2018 and December 31, 2017, there was an additional $3 million of unamortized debt expense related to the Revolving Credit Facility included in Other long-term assets, not included above.

Revolving Credit Facility

On June 18, 2015, the Partnership entered into the $1.75 billion Revolving Credit Facility, which was scheduled to mature on June 18, 2020, subject to an extension option, which could be exercised two times to extend the term of the Revolving Credit Facility, in each case, for an additional one-year term. As of March 31, 2018, there were no principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility.

The Revolving Credit Facility provided that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin was based on the Partnership's applicable credit ratings. As of March 31, 2018, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility required the Partnership to pay a fee on unused commitments. The commitment fee was based on the Partnership's applicable credit rating from the rating agencies. As of March 31, 2018, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Condensed Consolidated Statements of Income.

On April 6, 2018, the Partnership amended and restated the Revolving Credit Facility. See Note 16 for a discussion of the Second Amended and Restated Revolving Credit Agreement.

Commercial Paper

The Partnership has a commercial paper program, pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There were $596 million and $405 million outstanding under our commercial paper program at March 31, 2018 and December 31, 2017, respectively. The weighted average interest rate for the outstanding commercial paper was 2.72% as of March 31, 2018.

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Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement, providing for an unsecured three-year $450 million term loan agreement, which is scheduled to mature on July 31, 2018. The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of March 31, 2018, there was $450 million outstanding under the 2015 Term Loan Agreement, which is included as Current portion of long-term debt in the Partnership's Condensed Consolidated Balance Sheets.

The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of March 31, 2018, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Agreement was 1.375% based on the Partnership's credit ratings. For the three months ended March 31, 2018, the weighted average interest rate of the 2015 Term Loan Agreement was 2.98%.

Senior Notes

On March 9, 2017, the Partnership completed the public offering of $700 million aggregate principal amount of the Partnership's 4.400% Senior Notes due 2027. The Partnership received net proceeds of approximately $691 million. The proceeds were used for general partnership purposes, including to repay amounts outstanding under the Revolving Credit Facility. The 2027 Notes had an unamortized discount of $3 million and unamortized debt expense of $5 million at March 31, 2018, resulting in an effective interest rate of 4.58% during the three months ended March 31, 2018.

In addition to the 2027 Notes, as of March 31, 2018, the Partnership's debt included the 2019 Notes, 2024 Notes and 2044 Notes, which had $9 million of unamortized debt expense at March 31, 2018, resulting in effective interest rates of 2.57%, 4.02% and 5.08%, respectively, during the three months ended March 31, 2018.

As of March 31, 2018, the Partnership's debt included $250 million aggregate principal amount of EOIT's 6.25% senior notes due 2020. The EOIT Senior Notes had $11 million of unamortized premium at March 31, 2018, resulting in an effective interest rate of 3.80% during the three months ended March 31, 2018.

As of March 31, 2018, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(9) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership’s NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership’s natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership’s natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale

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of natural gas used in or produced by the Partnership’s operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership’s gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

As of March 31, 2018 and December 31, 2017, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may seek or be forced to enter into alternative arrangements. In that event, the Partnership’s financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership’s asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership’s processing contracts, which are not derivative instruments.

As of March 31, 2018 and December 31, 2017, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	March 31, 2018		December 31, 2017	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas — TBtu[1]				
Financial fixed futures/swaps	19	22	17	13
Financial basis futures/swaps	27	31	17	17
Physical purchases/sales	—	81	1	37
Crude oil (for condensate) — MBbl[2]				
Financial Futures/swaps	—	874	—	564
Natural gas liquids — MBbl[3]				
Financial Futures/swaps	—	2,195	—	1,615

(1) As of March 31, 2018, 82.4% of the natural gas contracts had durations of one year or less, 10.7% had durations of more than one year and less than two years and 6.9% had durations of more than two years. As of December 31, 2017, 67.7% of the natural gas contracts had durations of one year or less, 16.1% had durations of more than one year and less than two years and 16.2% had durations of more than two years.

(2) As of March 31, 2018, 69.1% of the crude oil (for condensate) contracts had durations of one year or less and 30.9% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) As of March 31, 2018, 72.0% of the natural gas liquids contracts had durations of one year or less and 28.0% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the natural gas liquid contracts had durations of one year or less.

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Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Condensed Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017 that were not designated as hedging instruments for accounting purposes are as follows:

		March 31, 2018		December 31, 2017	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current/Other	$3	$ 9	$ 5	$ 4
Physical purchases/sales	Other Current/Other	6	1	3	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current/Other	—	5	—	4
Natural gas liquids					
Financial Futures/swaps	Other Current/Other	2	2	1	5
Total gross derivatives (1)		$11	$ 17	$ 9	$ 13

(1) See Note 10 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Condensed Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Condensed Consolidated Statements of Income for the three months ended March 31, 2018 and 2017:

	Amounts Recognized in Income	
	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Natural gas		
Financial futures/swaps (losses) gains	$ (3)	$ 11
Physical purchases/sales gains	2	5
Crude oil (for condensate)		
Financial futures/swaps (losses) gains	(3)	3
Natural gas liquids		
Financial futures/swaps gains	4	2
Total	$ —	$ 21

For derivatives not designated as hedges in the tables above, amounts recognized in income for the periods ended March 31, 2018 and 2017, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Condensed Consolidated Statements of Income for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Change in fair value of derivatives	$ (2)	$ 24
Realized gain (loss) on derivatives	2	(3)
Gain on derivative activity	$ —	$ 21

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Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's senior unsecured debt rating to a below investment grade rating, at March 31, 2018, the Partnership would have been required to post $7 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at March 31, 2018. In addition, the Partnership could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(10) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Condensed Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude oil swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended March 31, 2018, there were no transfers between levels.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Condensed Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts due to their short-term nature and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments as of March 31, 2018 and December 31, 2017.

	March 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) [1]	$ —	$ —	$ —	$ —
2015 Term Loan Agreement (Level 2)	450	450	450	450
2019 Notes (Level 2)	500	494	500	497
2024 Notes (Level 2)	600	588	600	602
2027 Notes (Level 2)	697	687	697	712
2044 Notes (Level 2)	550	523	550	550
EOIT Senior Notes (Level 2)	261	261	263	265

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $596 million and $405 million of commercial paper was outstanding as of March 31, 2018 and December 31, 2017, respectively.

The fair value of the Partnership's Revolving Credit Facility, 2015 Term Loan Agreement, EOIT Senior Notes, 2019 Notes, 2024 Notes, 2027 Notes and 2044 Notes is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). As of March 31, 2018, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2018 and December 31, 2017:

March 31, 2018	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$3	$ 7	$ —	$ —
Significant other observable inputs (Level 2)	6	8	19	8
Unobservable inputs (Level 3)	2	2	—	—
Total fair value	11	17	19	8
Netting adjustments	(3)	(3)	—	—
Total	$8	$ 14	$ 19	$ 8

December 31, 2017	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$5	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	4	5	27	12
Unobservable inputs (Level 3)	—	5	—	—
Total fair value	9	13	27	12
Netting adjustments	(5)	(5)	—	—
Total	$4	$ 8	$ 27	$ 12

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of March 31, 2018 and December 31, 2017.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $16 million and $10 million at March 31, 2018 and December 31, 2017, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of zero at March 31, 2018 and December 31, 2017, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in the fair value of our Level 3 commodity contracts between the periods presented.

	Commodity Contracts
	Natural gas liquids financial futures/swaps

	(In millions)
Balance at December 31, 2017	$ (5)
Gains included in earnings	4
Settlements	1
Transfers out of Level 3	—
Balance as of March 31, 2018	$ —

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	March 31, 2018	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$ —	$0.2663 - $0.8963

(11) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 29	$ 14
Income taxes, net of refunds	2	—
Non-cash transactions:		
Accounts payable related to capital expenditures	50	20

The following table reconciles cash and cash equivalents and restricted cash on the Condensed Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Condensed Consolidated Statements of Cash Flows:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Cash and cash equivalents	$ 30	$ 17
Restricted cash	14	14
Cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 44	$ 31

(12) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy’s LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas. Those services include firm transportation with seasonal contract demand, firm storage, no notice transportation with associated storage and maximum rate firm transportation. Contracts for firm transportation with seasonal contract demand, firm storage, firm no notice transportation with storage for CenterPoint’s LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas are in effect through March 21, 2021 and will remain in effect thereafter unless and until terminated by either party upon 180 days’ prior written notice. Contracts for maximum firm rate transportation for CenterPoint’s LDCs in Oklahoma and portions of Northeast Texas are also in effect through March 21, 2021. Contracts for CenterPoint’s LDCs in Arkansas, Louisiana and Texarkana, Texas terminated on March 31, 2018. MRT provides transportation and storage services to CenterPoint Energy’s LDCs in Arkansas and Louisiana.

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Contracts for these services are in effect through May 15, 2023 and will remain in effect thereafter unless and until terminated by either party upon 12 months' prior written notice.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy. On March 17, 2014, EOIT entered into a transportation agreement with OGE Energy, with a primary term of May 1, 2014 through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

On December 6, 2016, EOIT entered into a transportation agreement with OGE Energy, with a primary term expected to begin in late 2018 and extend for 20 years. In connection with the agreement, an approximately 80-mile pipeline will be built to expand the EOIT system.

Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchases natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 7% and 6% of total revenues during the three months ended March 31, 2018 and 2017, respectively. Amounts of revenues from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Gas transportation and storage service revenue — CenterPoint Energy	$ 33	$ 33
Natural gas product sales — CenterPoint Energy	6	—
Gas transportation and storage service revenue — OGE Energy	9	9
Natural gas product sales — OGE Energy	1	—
Total revenues — affiliated companies	$ 49	$ 42

Amounts of natural gas purchased from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	

Cost of natural gas purchases — CenterPoint Energy	$ 2	$ —
Cost of natural gas purchases — OGE Energy	3	3
Total cost of natural gas purchases — affiliated companies	$ 5	$ 3

Seconded employees, corporate services and operating lease expense

As of March 31, 2018, the Partnership had certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at actual cost subject to a cap of $5 million in 2018 and thereafter, unless and until secondment is terminated.

The Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under services agreements for an initial term that ended on April 30, 2016. The services agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate the services agreements at any time with 180 days' notice, if approved by the Board of Enable GP.

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The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2018 are $4 million and $1 million, respectively.

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease commenced on October 1, 2016 and extends through December 31, 2019. The Partnership expects to incur approximately $3 million in rent and maintenance expenses during the initial term of the lease. As of March 31, 2018, CenterPoint Energy continues to provide office and data center space to the Partnership in Houston, Texas, under the services agreement. During the first quarter of 2018 the Partnership provided notice to Centerpoint Energy of its intent to terminate the provision of office space in Houston, Texas on August 31, 2018.

Amounts charged to the Partnership by affiliates for seconded employees, an operating lease and corporate services, included primarily in Operation and maintenance and General and administrative expenses in the Partnership's Condensed Consolidated Statements of Income are as follows:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Corporate Services — CenterPoint Energy	$ 1	$ 1
Operating Lease — CenterPoint Energy	—	—
Seconded Employee Costs — OGE Energy	8	7
Corporate Services — OGE Energy	—	1
Total corporate services and seconded employees expense	$ 9	$ 9

Series A Preferred Units

On February 18, 2016, the Partnership completed a private placement to CenterPoint Energy of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 6 for further discussion of the Series A Preferred Units.

(13) Commitments and Contingencies

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(14) Equity-Based Compensation

The following table summarizes the Partnership's compensation expense for the three months ended March 31, 2018 and 2017 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Performance units	$ 3	$ 3
Restricted units	1	—
Phantom units	1	1
Total compensation expense	$ 5	$ 4

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Units Outstanding

The Partnership periodically grants performance units, restricted units and phantom units to certain employees under the Enable Midstream Partners, LP Long Term Incentive Plan. A summary of the activity for the Partnership’s performance units, restricted units, and phantom units applicable to the Partnership’s employees at March 31, 2018 and changes during 2018 are shown in the following table.

	Performance Units		Restricted Units		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units Outstanding at December 31, 2017	2,040,407	$13.86	222,434	$17.87	987,380	$11.38
Granted (1)	529,408	17.70	—	—	494,072	14.04
Vested (2)	(401,772)	12.59	(181,068)	16.75	—	—
Forfeited	(3,725)	13.87	(1,366)	16.75	(7,375)	11.90
Units Outstanding at March 31, 2018	2,164,318	$13.95	40,000	$22.96	1,474,077	$12.27
Aggregate Intrinsic Value of Units Outstanding at March 31, 2018	$30		$1		$20	

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(1) Performance units represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.

(2) Performance units vested as of March 31, 2018 include 401,772 units from the annual grant, which were approved by the Board of Directors in 2015 and paid out at 200%, or 803,544 units, based on the level of achievement of a performance goal established by the Board of Directors over the performance period. The Board of Directors approved the accelerated vesting of the 2015 grant from June 1, 2018 to March 1, 2018.

Unrecognized Compensation Cost

A summary of the Partnership’s unrecognized compensation cost for its non-vested performance units, restricted units, and phantom units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	March 31, 2018	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$19	1.66
Restricted Units	—	0.22
Phantom Units	12	1.86
Total	$31	

As of March 31, 2018, there were 7,504,634 units available for issuance under the long-term incentive plan.

(15) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies excerpt in the Partnership's audited 2017 consolidated financial statements included in the Annual Report. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers, and

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(ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to our producer, power plant, LDC and industrial end-user customers.

Financial data for reportable segments are as follows:

Three Months Ended March 31, 2018	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$418	$ 140	$ (115)	$443
Service revenue	173	139	(7)	305
Total Revenues	591	279	(122)	748
Cost of natural gas and natural gas liquids	358	139	(122)	375
Operation and maintenance, General and administrative	76	46	(1)	121
Depreciation and amortization	62	34	—	96
Taxes other than income tax	10	7	—	17
Operating income	$85	$ 53	$ 1	$139
Capital expenditures	$147	$ 43	$ —	$190
Total assets	$9,212	$ 5,652	$ (3,177)	$11,687

Three Months Ended March 31, 2017	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$351	$ 153	$ (118)	$386
Service revenue	140	141	(1)	280
Total Revenues	491	294	(119)	666
Cost of natural gas and natural gas liquids	286	140	(118)	308
Operation and maintenance, General and administrative	70	45	(1)	114
Depreciation and amortization	56	32	—	88
Taxes other than income tax	9	7	—	16
Operating income	$70	$ 70	$ —	$140
Capital expenditures	$51	$ 10	$ —	$61
Total assets as of December 31, 2017	$9,079	$ 5,616	$ (3,102)	$11,593

(1) See Note 7 for discussion regarding ownership interests in SESH and related equity earnings included in the transportation and storage segment for the three months ended March 31, 2018 and 2017.

(16) Subsequent Event

On April 6, 2018, the Partnership amended and restated the Revolving Credit Facility in its entirety. The amended and restated Revolving Credit Facility is a $1.75 billion 5-year senior unsecured revolving credit facility, which under certain circumstances may be increased from time to time up to an additional $875 million, in aggregate. The Second Amended and Restated Revolving Credit Facility contains an option, which may be exercised up to two times, to extend the Second Amended and Restated Revolving Credit Facility for an additional one-year term.

The Second Amended and Restated Revolving Credit Facility provides that outstanding borrowings bear interest at the Eurodollar rate and/or an alternate base rate, at the Partnership’s election, plus an applicable margin. The applicable margin will be based on the Partnership’s designated credit ratings. The applicable margin shall equal, in the case of interest rates determined by reference to the Eurodollar rate, between 1.00% and 1.75% per annum.

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The Second Amended and Restated Revolving Credit Facility requires the Partnership to pay a quarterly fee on each lender’s unused commitment amount during such preceding quarter which shall equal between 0.10% and 0.30% per annum, depending on The Partnership’s designated credit rating. The Second Amended and Restated Revolving Credit Facility provides for issuance of letters of credit of up to $500 million dollars at any time outstanding. The Second and Amended Restated Revolving Credit Facility contains a financial covenant requiring the Partnership to maintain a ratio of consolidated funded debt to EBITDA as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00, although such ratio is increased to 5.50 to 1.00 for a certain period of time following an acquisition by the Partnership or certain of its subsidiaries with a purchase price that, when combined with the aggregate purchase price for all other such acquisitions in any rolling 12-month period, is equal to or greater than $25 million.

The Second Amended and Restated Revolving Credit Facility also contains covenants that restrict the Partnership and certain of its subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as excluded subsidiaries, restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. The Second Amended and Restated Revolving Credit Facility is subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100 million or more in the aggregate, change of control, nonpayment of uninsured judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes included herein and our audited consolidated financial statements for the year ended December 31, 2017, included in our Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read “Forward-Looking Statements.” In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

Enable Midstream Partners, LP is a Delaware limited partnership formed in May 2013 by CenterPoint Energy, OGE Energy and ArcLight to own, operate and develop midstream energy infrastructure assets strategically located to serve our customers. We completed our initial public offering in April 2014, and we are traded on the NYSE under the symbol “ENBL.” Our general partner is owned by CenterPoint Energy and OGE Energy. In this report, the terms “Partnership” and “Registrant” as well as the terms “our,” “we,” “us” and “its,” are sometimes used as abbreviated references t Enable Midstream Partners, LP together with its consolidated subsidiaries.

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. Our transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Our natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Our crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. Our natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma and our investment in SESH, an interstate pipeline extending from Louisiana to Alabama.

We expect our business to continue to be affected by the key trends included in our Annual Report, as well as the recent developments discussed herein. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Our primary business objective is to increase the cash available for distribution to our unitholders over time while maintaining our financial flexibility. Our business strategies for achieving this objective include capitalizing on organic growth opportunities

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associated with our strategically located assets, growing through accretive acquisitions, maintaining strong customer relationships to attract new volumes and expand beyond our existing asset footprint and business lines, and continuing to minimize direct commodity price exposure through fee-based contracts. As part of these efforts, we continuously engage in discussions with new and existing customers regarding the development of potential projects to develop new midstream assets to support their needs as well as discussions with potential counterparties regarding opportunities to purchase or invest in complementary assets in new operating areas or midstream business lines. These growth, acquisition and development efforts often involve assets which, if acquired or constructed, could have a material effect on our financial condition and results of operations.

Recent Developments

Regulatory Update

Interstate Natural Gas Transportation Regulation

Effective December 22, 2017, the Tax Cuts and Jobs Act of 2017 changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. FERC issued a Revised Policy Statement on Treatment of Income Taxes stating that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates. FERC issued the Revised Policy Statement in response to a remand from the U.S. Court of Appeals for the D.C. Circuit in United Airlines v. FERC, in which the court determined that FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not “double recover” its taxes under the current policy by both including an income-tax allowance in its cost-of-service and earning a return on equity calculated using the discounted cash flow methodology. Requests for rehearing or clarification of the Revised Policy Statement are pending and FERC may change its decision in response to these requests. Accordingly, the impacts that such changes may have on the rates the Partnership can charge for transportation services are unknown at this time.

FERC also issued a Notice of Inquiry (NOI) requesting comments on the effect of the Tax Cuts and Jobs Act of 2017 on FERC-jurisdictional rates. The NOI states that of particular interest to FERC is whether, and if so how, FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Comments in response to the NOI are due on or before May 21, 2018. Actions FERC will take, if any, following receipt of responses to the NOI and any potential impacts from final rules or policy statements issued following the NOI on the rates the Partnership can charge for transportation services are unknown at this time, but could impact rates the Partnership is permitted to charge its customers.

Included in the March 15, 2018 issuances is a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. The NOPR proposes a new rule that will, if it becomes a final rule, require all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information. The NOPR suggests that this information will allow FERC and other stakeholders to evaluate the impacts of the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement on each individual pipeline’s rates. The NOPR proposes that each FERC-regulated natural gas pipeline will select one of four options: file a limited NGA Section 4 filing reducing its rates only as required in relation to the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. Comments on the NOPR are due April 25, 2018, and once the comment period is complete, FERC may issue a final rule. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulation in its proposed form could impact the rates the

Partnership is permitted to charge its customers.

Even without action on the NOPR or NOI, the FERC or our shippers may challenge the cost of service rates we charge. FERC's establishment of a just and reasonable rate is based on many components, and tax-related changes will affect tax-related accounts, such as the annual allowance for income taxes and the balance sheet amounts for accumulated deferred income taxes and related regulatory assets and liabilities, while other pipeline costs also will continue to affect FERC's determination of just and reasonable cost-of-service rates. Although changes in these tax-related accounts may vary, other components in the cost-of-service rate calculation may also change and result in a newly calculated cost-of-service rate that is the same as or greater than the prior cost-of-service rate. Moreover, pipelines receive revenues from cost-of-service rates, negotiated rates, discounted rates, and market-based rates, or a combination thereof. As of December 31, 2017, approximately 62% and 0% of our aggregate contracted firm transportation capacity on EGT and MRT, respectively, was subscribed under negotiated rate contracts. As of December 31, 2017, approximately 100% and 0% of our aggregated contracted firm storage capacity on EGT and MRT, respectively, was subscribed under negotiated rate contracts. As of December 31, 2017, approximately 23% and 41% of our aggregate contracted firm transportation capacity on EGT and MRT, respectively, was subscribed under discounted rate contracts. We do not expect rates subject to negotiated rates that are not tied to the cost-of-service rates to be affected by the Revised Policy Statement or any

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final regulations that may result from the March 15, 2018 issuances. Nor will discounted rates which are below the level of any new maximum rate be affected. With respect to the cost-of-service rates, depending on a detailed review of all of the Partnership's cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers, the NOI, the NOPR, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Cuts and Jobs Act of 2017, the revenues associated with natural gas transportation services we provide pursuant to cost-of-service based rates may decrease in the future.

The FERC issued a Notice of Inquiry on April 19, 2018 (April 2018 NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the April 2018 NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would materially affect our plans and operations.

Interstate Crude Oil Transportation Regulation

FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23%. Many existing pipelines, including our Williston Basin crude oil gathering systems, utilize the FERC oil index to change transportation rates annually every July 1. With respect to oil and refined products pipelines subject to FERC jurisdiction, the Revised Policy Statement requires the pipeline to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on the Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 in the determination of indexed rates prospectively, effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

Imposition of Ad Valorem Tariffs

The construction of pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to costs and availability of equipment and materials such as steel. If third party providers of steel products essential to our capital improvements and additions are unable to obtain raw materials, including steel, at historical prices, they may raise the price we pay for such products. On March 8, 2018, the President issued two proclamations directing the imposition of ad valorem tariffs of 25 percent on certain imported steel products and 10 percent on certain imported aluminum products. Following these proclamations, domestic prices for steel have risen and are expected to continue to rise. While steel pipe costs relating to our previously announced projects are fixed for 2018, the price increases may result in increased costs associated with the continued build-out of our gathering systems as well as projects under development. If we are not able to pass these cost increases along to our customers, our Income from operations and cash flows may be adversely affected.

Commercial and Construction Update

Project Wildcat rich gas takeaway solution

The Partnership has entered into an agreement to deliver approximately 400 MMcf/d of rich natural gas from the Anadarko Basin to north Texas, providing a new market outlet for growing Anadarko Basin production. Project Wildcat is expected to provide access to the Texas intrastate natural gas markets, including the Tolar Hub, by contracting with an affiliate of Energy Transfer Partners, LP for 400 MMcf/d of firm processing capacity at the Godley Plant in Johnson County, Texas. The project is expected to be in service by the end of the second quarter of 2018. Even with the 400 MMcf/d of processing capacity provided by this project, the Partnership anticipates that there will be a need to resume construction of the previously announced Wildhorse Plant, though likely not before 2019.

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EGT and EOIT Expansion Projects

Newfield Exploration Company has entered into a 205,000 Dth/d firm natural gas transportation agreement with EGT related to the Cana and STACK Expansion (CaSE) project, a system expansion providing firm transportation service for growing Anadarko Basin production. The 10-year contract is expected to start at an initial capacity of 45,000 Dth/d in early 2018 and grow to the full contracted capacity by the fourth quarter of 2018. The Muskogee project, a 20-year, 228,000 Dth/d firm transportation service agreement with Oklahoma Gas and Electric on the EOIT system, is expected to commence service in late 2018.

CenterPoint Strategic Review

CenterPoint Energy has publicly disclosed that it is evaluating strategic alternatives for its investment in the Partnership. CenterPoint Energy has disclosed that the alternatives may include a sale of all or a portion of the interests that it owns in the Partnership and Enable GP, that if the sale option is not viable it intends to reduce its ownership in the Partnership over time through a sale in the public equity markets of Partnership common units that it holds, subject to market conditions, and that there can be no assurances that these evaluations will result in any specific action.

Liquidity Update

Second Amended and Restated Revolving Credit Facility

On April 6, 2018, the Partnership amended and restated the Revolving Credit Facility in its entirety. For more information, please see Note 16 of the Notes to Condensed Consolidated Financial Statements.

Results of Operations

The following tables summarize the key components of our results of operations for the three months ended March 31, 2018 and 2017.

Three Months Ended March 31, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$418	$ 140	$ (115)	$ 443
Service revenue	173	139	(7)	305
Total Revenues	591	279	(122)	748
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	358	139	(122)	375
Gross margin [1]	233	140	—	373
Operation and maintenance, General and administrative	76	46	(1)	121
Depreciation and amortization	62	34	—	96
Taxes other than income tax	10	7	—	17
Operating income	$85	$ 53	$ 1	$ 139
Equity in earnings of equity method affiliate	$—	$ 6	$ —	$ 6

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Three Months Ended March 31, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$351	$ 153	$ (118)	$ 386
Service revenue	140	141	(1)	280
Total Revenues	491	294	(119)	666
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	286	140	(118)	308
Gross margin [1]	205	154	(1)	358
Operation and maintenance, General and administrative	70	45	(1)	114
Depreciation and amortization	56	32	—	88
Taxes other than income tax	9	7	—	16
Operating income	$70	$ 70	$ —	$ 140
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

(1) Gross margin is a non-GAAP measure and is reconciled to its most directly comparable financial measures calculated and presented below under the caption Reconciliations of Non-GAAP Financial Measures.

	Three Months Ended March 31, 2018	2017
Operating Data:		
Gathered volumes—TBtu	385	296
Gathered volumes—TBtu/d	4.28	3.29
Natural gas processed volumes—TBtu	200	168
Natural gas processed volumes—TBtu/d	2.22	1.87
NGLs produced—MBbl/d [1]	110.29	79.76
NGLs sold—MBbl/d [1][2]	109.39	78.65
Condensate sold—MBbl/d	6.96	5.47
Crude Oil—Gathered volumes—MBbl/d	24.83	21.18
Transported volumes—TBtu	510	493
Transported volumes—TBtu/d	5.66	5.48
Interstate firm contracted capacity—Bcf/d	6.05	7.23
Intrastate average deliveries—TBtu/d	1.97	1.84

(1) Excludes condensate.
(2) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

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	Three Months Ended March 31,	
	2018	2017
Anadarko		
Gathered volumes—TBtu/d	2.02	1.75
Natural gas processed volumes—TBtu/d	1.82	1.54
NGLs produced—MBbl/d (1)	95.85	67.30
Arkoma		
Gathered volumes—TBtu/d	0.54	0.57
Natural gas processed volumes—TBtu/d	0.10	0.10
NGLs produced—MBbl/d (1)	4.98	4.85
Ark-La-Tex		
Gathered volumes—TBtu/d	1.71	0.97
Natural gas processed volumes—TBtu/d	0.29	0.23
NGLs produced—MBbl/d (1)	9.46	7.61

(1) Excludes condensate.

Gathering and Processing

Three Months Ended March 31, 2018 compared to three months ended March 31, 2017. Our gathering and processing segment reported operating income of $85 million for the three months ended March 31, 2018 compared to operating income of $70 million for the three months ended March 31, 2017. The difference of $15 million in operating income between periods was primarily due to a $28 million increase in gross margin. This was partially offset by a $6 million increase in operation and maintenance and general and administrative expenses, a $6 million increase in depreciation and amortization and a $1 million increase in taxes other than income tax during the three months ended March 31, 2018.

Our gathering and processing segment revenues increased $100 million. The increase was primarily due to the following:

- revenues from NGL sales increased $89 million resulting from higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins,
- natural gas gathering revenues increased $14 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins,
- processing service revenues increased $13 million resulting from higher processed volumes primarily under fixed processing arrangements,
- revenues from natural gas sales increased $3 million due to higher gathered volumes in the Anadarko and Ark-La-Tex Basins as well as higher average natural gas prices, and
- crude oil and water gathering revenues increased $1 million due to an increase in gathered volumes.

These increases were partially offset by a $14 million decrease due to the adoption of ASC 606, which resulted in a corresponding increase in Cost of natural gas and natural gas liquids, see Note 3 for further information regarding the adoption of ASC 606. The increase was also offset by a $7 million decrease in revenues from changes in the fair value of natural gas, condensate and NGL derivatives.

Our gathering and processing segment gross margin increased $28 million. The increase was primarily due to the following:

- processing margins increased $19 million from higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basin,
- natural gas gathering margin increased $15 million due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins, and
- crude oil and water gathering margins increased $1 million as a result of an increase in gathered volumes.

These increases were partially offset by a $7 million decrease in gross margin from changes in the fair value of natural gas, condensate and NGL derivatives.

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Our gathering and processing segment operation and maintenance and general and administrative expenses increased $6 million. The increase was primarily due to a $3 million increase in payroll-related costs, a $2 million increase in compressor rental expenses due to increased compression activity and a $2 million increase in materials and supplies expense. These were partially offset by a $2 million decrease due to an increase in capitalized overhead costs as a result of an increase in projects in the first quarter of 2018 and a $1 million change in the allowance for doubtful accounts due to the collection of accounts receivable in the three months ended March 31, 2018 that were previously included in the allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $6 million due to additional assets placed in service primarily as a result of the Align Midstream, LLC acquisition in the fourth quarter of 2017.

Our gathering and processing segment taxes other than income tax increased $1 million due to higher accrued ad valorem taxes due to additional assets placed in service.

Transportation and Storage

Three Months Ended March 31, 2018 compared to three months ended March 31, 2017. Our transportation and storage segment reported operating income of $53 million for the three months ended March 31, 2018 compared to operating income of $70 million for the three months ended March 31, 2017. The difference of $17 million in operating income between periods was primarily due to a $14 million decrease in gross margin, a $2 million increase in depreciation and amortization and a $1 million increase in operation and maintenance and general and administrative expenses for the three months ended March 31, 2018.

Our transportation and storage segment revenues decreased $15 million. The decrease was primarily due to the following:
- changes in the fair value of natural gas derivatives decreased $19 million and
- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $12 million due to contract expirations in the second quarter of 2017.

These decreases were partially offset by:
- volume-dependent transportation revenues increased $5 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates,
- revenues from natural gas sales increased $3 million due to higher sales volumes and higher average sales prices,
- other firm transportation services increased $4 million due to new intrastate transportation contracts,
- realized gains on natural gas derivatives increased $4 million, and
- revenues from NGL sales increased $1 million due to an increase in prices and volumes.

Our transportation and storage segment gross margin decreased $14 million. The decrease was primarily due to the following:
- changes in the fair value of natural gas derivatives decreased $19 million,
- firm transportation services of between Carthage, Texas and Perryville, Louisiana decreased $12 million due to contract expirations in the second quarter of 2017, and
- storage decreased $6 million primarily due to storage field losses of $3 million and a lower of cost or net realizable value adjustment of $3 million in the first quarter of 2018.

These decreases were partially offset by:
- system management activities increased $10 million,
-

volume-dependent transportation margins increased $5 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates,

- other firm transportation services increased $4 million due to new intrastate contracts, and
- realized gains on natural gas derivatives increased $4 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $1 million. The increase was primarily due to a $1 million increase in payroll-related costs and a $1 million increase in one-time reimbursements associated with an unplanned pipeline outage. These increases were partially offset by a $1 million decrease due to increased capitalized overhead costs.

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Our transportation and storage segment depreciation and amortization increased $2 million due to additional assets placed in service.

Condensed Consolidated Interim Information

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Operating Income	$139	$140
Other Income (Expense):		
Interest expense	(33)	(27)
Equity in earnings of equity method affiliate	6	7
Other, net	2	1
Total Other Expense	(25)	(19)
Income Before Income Taxes	114	121
Income tax expense	—	1
Net Income	$114	$120
Less: Net income attributable to noncontrolling interest	—	—
Net Income Attributable to Limited Partners	$114	$120
Less: Series A Preferred Unit distributions	9	9
Net Income Attributable to Common and Subordinated Units	$105	$111

Three Months Ended March 31, 2018 compared to Three Months Ended March 31, 2017

Net Income attributable to limited partners. We reported net income attributable to limited partners of $114 million in the three months ended March 31, 2018 compared to net income attributable to limited partners of $120 million in the three months ended March 31, 2017. The decrease in net income attributable to limited partners of $6 million was primarily attributable to an increase in interest expense of $6 million in the three months ended March 31, 2018.

Interest Expense. Interest expense increased $6 million primarily due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in March 2017 that resulted in the repayment of amounts outstanding under the Partnership's Revolving Credit Facility.

Reconciliations of Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio in this report based on information in its condensed consolidated financial statements. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are part of the performance measures that we use to manage the Partnership.

Provided below are reconciliations of Gross margin to total revenues, Adjusted EBITDA and DCF to net income attributable to limited partners, and Adjusted EBITDA to net cash provided by operating activities and Adjusted interest expense to interest expense, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio should not be considered as alternatives to net income, operating income, total revenues, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. These non-GAAP financial measures have important limitations as analytical tools because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in the Partnership’s industry, these measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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	Three Months Ended March 31, 2018	2017
	(In millions)	
Reconciliation of Gross margin to Total Revenues:		
Consolidated		
Product sales	$443	$386
Service revenue	305	280
Total Revenues	748	666
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	375	308
Gross margin	$373	$358
Reportable Segments		
Gathering and Processing		
Product sales	$418	$351
Service revenue	173	140
Total Revenues	591	491
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	358	286
Gross margin	$233	$205
Transportation and Storage		
Product sales	$140	$153
Service revenue	139	141
Total Revenues	279	294
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	139	140
Gross margin	$140	$154

The following table shows the components of our gross margin for the three months ended March 31, 2018:

	Fee-Based (1)			
	Demand	Volume-Dependent	Commodity-Based (1)	Total
Three Months Ended March 31, 2018				
Gathering and Processing Segment	22 %	52 %	26 %	100 %
Transportation and Storage Segment	85 %	14 %	1 %	100 %
Partnership Weighted Average	45 %	38 %	17 %	100 %

(1) For purposes of this table, the Partnership includes the value of all natural gas and NGL commodities received as payment as commodity-based.

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	Three Months Ended March 31, 2018	2017
	(In millions, except Distribution coverage ratio)	
Reconciliation of Adjusted EBITDA and DCF to net income attributable to limited partners and calculation of Distribution coverage ratio:		
Net income attributable to limited partners	$114	$120
Depreciation and amortization expense	96	88
Interest expense, net of interest income	33	27
Income tax expense	—	1
Distributions received from equity method affiliate in excess of equity earnings	7	4
Non-cash equity-based compensation	5	4
Change in fair value of derivatives	2	(24)
Other non-cash losses [1]	—	1
Adjusted EBITDA	$257	$221
Series A Preferred Unit distributions [2]	(9)	(9)
Distributions for phantom and performance units [3]	(3)	—
Adjusted interest expense [4]	(35)	(27)
Maintenance capital expenditures	(14)	(14)
DCF	$196	$171
Distributions related to common and subordinated unitholders [5]	$138	$137
Distribution coverage ratio	1.42	1.25

(1) Other non-cash losses includes loss on sale of assets and write-downs of materials and supplies.

(2) This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the three months ended March 31, 2018 and 2017. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

(3) Distributions for phantom and performance units represent distribution equivalent rights paid in cash. Phantom unit distribution equivalent rights are paid during the vesting period and performance unit distribution equivalent rights are paid at vesting.

(4) See below for a reconciliation of Adjusted interest expense to Interest expense.

(5) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. Amounts for 2018 reflect estimated cash distributions for common units outstanding for the quarter ended March 31, 2018.

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	Three Months Ended March 31, 2018	2017
	(In millions)	
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:		
Net cash provided by operating activities	$166	$156
Interest expense, net of interest income	33	27
Other non-cash items [(1)]	(1)	1
Changes in operating working capital which (provided) used cash:		
Accounts receivable	(23)	(10)
Accounts payable	60	55
Other, including changes in noncurrent assets and liabilities	13	12
Return of investment in equity method affiliate	7	4
Change in fair value of derivatives	2	(24)
Adjusted EBITDA	$257	$221

(1) Other non-cash items include amortization of debt expense, discount and premium on long-term debt and write-downs of materials and supplies.

	Three Months Ended March 31, 2018	2017
	(In millions)	
Reconciliation of Adjusted interest expense to Interest expense:		
Interest Expense	$33	$27
Amortization of premium on long-term debt	1	1
Capitalized interest on expansion capital	2	—
Amortization of debt expense and discount	(1)	(1)
Adjusted interest expense	$35	$27

Liquidity and Capital Resources

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of March 31, 2018, we had a working capital deficit of $991 million. The deficit is primarily due to the classification of $450 million of borrowings under the 2015 Term Loan Agreement as Current portion of long-term debt as of March 31, 2018 as well as $596 million of commercial paper outstanding as of March 31, 2018. We utilize our commercial paper program and Revolving Credit Facility to manage the timing of cash flows and fund short-term working capital deficits.

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Cash Flows

The following tables reflect cash flows for the applicable periods:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Net cash provided by operating activities	$166	$156
Net cash used in investing activities	$(176)	$(56)
Net cash provided by (used in) financing activities	$35	$(92)

Operating Activities

The increase of $10 million, or 6%, in net cash provided by operating activities for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 was primarily driven by an increase of $8 million in other non-cash items and an increase of $7 million in the timing of cash receipts and disbursements and changes in other working capital assets and liabilities, partially offset by a decrease in net income of $6 million.

Investing Activities

The increase of $120 million, or 214%, in net cash used in investing activities for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 was primarily due to higher capital expenditures of $129 million partially offset by an increase in proceeds from sale of asset of $6 million due to the sale of a cryogenic processing plant, previously included in assets held for sale, in the first quarter 2018 and an increase in return of investment in equity method affiliate of $3 million.

Financing Activities

Net cash provided by financing activities increased $127 million, or 138%, for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Our primary financing activities consist of the following:

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Proceeds from 2027 Notes, net of issuance costs	$—	$691
Net (repayments) proceeds from Revolving Credit Facility	—	(636)
Proceeds from commercial paper program	190	—
Distributions	(150)	(147)
Cash taxes paid for employee equity-based compensation	(5)	—

Please see Note 8, "Debt" in the Notes to the Unaudited Condensed Consolidated Financial Statements in Part 1, Item 1. for a description of the Partnership's debt agreements.

Sources of Liquidity

As of March 31, 2018, our sources of liquidity included:

- cash on hand;
- cash generated from operations;
- proceeds from commercial paper issuances;
- borrowings under our Revolving Credit Facility; and
- capital raised through debt and equity markets.

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ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement, pursuant to which the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. The Partnership did not sell any common units under the ATM Program during the three months ended March 31, 2018.

Distribution Reinvestment Plan

In June 2016, the Partnership implemented a Distribution Reinvestment Plan, which offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units. The Partnership will have the sole discretion to determine whether common units purchased under the DRIP will come from our newly issued common units or from common units purchased on the open market. The purchase price for newly issued common units will be the average of the high and low trading prices of the common units on the New York Stock Exchange-Composite Transactions for the five trading days immediately preceding the investment date. The purchase price for common units purchased on the open market will be the weighted average price of all common units purchased for the DRIP for the respective investment date. We can set a discount ranging from 0% to 5% for common units purchased pursuant to the DRIP. The discount is currently set at 0%. Participation in the DRIP is voluntary, and once enrolled, our unitholders may terminate participation at any time.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income; and
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Our future capital expenditures may vary significantly from period to period based on commodity prices and the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, issuances of commercial paper, borrowings under our Revolving Credit Facility, new debt offerings or the issuance of additional partnership units. Issuances of equity or debt in the capital markets may not, however, be available to us on acceptable terms.

Distributions

On May 1, 2018, the board of directors of Enable GP declared a quarterly cash distribution of $0.318 per common unit on all of the Partnership’s outstanding common units for the period ended March 31, 2018. The distributions will be paid May 29, 2018 to unitholders of record as of the close of business on May 22, 2018. Additionally, the board of directors of Enable GP declared a quarterly cash distribution of $0.625 on the Partnership’s outstanding Series A Preferred Units. The distributions will be paid May 15, 2018 to unitholders of record as of the close of business on May 1, 2018.

Expiration of Subordination Period

The financial tests required for conversion of all subordinated units were met and the 207,855,430 outstanding subordinated units converted into common units on a one-for-one basis on August 30, 2017. The conversion of the subordinated units did not change the aggregate amount of outstanding units, and the conversion of the subordinated units did not impact the amount of cash available for distribution by the Partnership.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

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Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy commodities will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We examine the creditworthiness of third party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

Critical Accounting Policies and Estimates

The Partnership's critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 of the Notes to the Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" in our Annual Report. The accounting policies and estimates used in preparing our interim Condensed Consolidated Financial Statements for the three months ended March 31, 2018 are the same as those described in our Annual Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including volatility in commodity prices and interest rates.

Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to fee-based contracts that include minimum volume commitments and/or demand fees, we are also directly and indirectly exposed to changes in the prices of natural gas, condensate and NGLs. The Partnership utilizes derivatives and forward commodity sales to mitigate the effects of price changes. We do not enter into risk management contracts for speculative purposes. For further information regarding our derivatives, see Note 9 of the Notes to the Unaudited Condensed Consolidated Financial Statements.

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 14% of our total gross margin for the twelve months ending December 31, 2018 is directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to commodity prices in certain agreements. Since March 31, 2018, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the nine months ending December 31, 2018.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next nine months. Based on a sensitivity analysis, a 10% decrease in prices from forecasted levels would decrease net income by approximately $9 million for natural gas and ethane and $8 million for NGLs (other than ethane) and condensate, excluding the impact of hedges, for the remaining nine months ending December 31, 2018.

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is substantially comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. Borrowings under our Revolving Credit Facility, 2015 Term Loan Agreement and any issuances under our commercial paper program are at a variable interest rate and expose us to the risk of increasing interest rates. Based upon the $1,046 million outstanding borrowings under commercial paper and the 2015 Term Loan Agreement as of March 31, 2018, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $10 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange

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Act of 1934, as amended (the “Exchange Act”)) as of March 31, 2018. Based on such evaluation, our management has concluded that, as of March 31, 2018, our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms and that information is accumulated and communicated to our management, including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal controls over financial reporting during the quarter ended March 31, 2018, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding legal proceedings is set forth in Note 13 - Commitments and Contingencies to the Partnership’s condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report on Form 10-Q and is incorporated herein by reference.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. Except as set forth below, there have been no material changes in our risk factors from those previously disclosed under “Risk Factors” in our Annual Report.

Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

The rates charged by several of our pipeline systems, including for interstate gas transportation service provided by our intrastate pipelines, are regulated by FERC. FERC and state regulatory agencies also regulate other terms and conditions of the services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose or offer, the profitability of our pipeline businesses could suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit our profitability. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Our natural gas interstate pipelines are regulated by FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EPAct of 2005. Generally, FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPACT 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to approximately $1.2 million per violation.

FERC's jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from FERC. Certain minor expansions are authorized by blanket certificates that FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Our inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

FERC conducts audits to verify compliance with FERC's regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. FERC's regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of our intrastate pipelines and for services offered at certain of our storage facilities are subject to the jurisdiction of FERC under Section 311 of the NGPA. Rates to provide such interstate transportation service must be "fair and equitable" under the NGPA and are subject to review, refund with interest if found not to be fair and equitable, and approval by FERC at least once every five years.

Our crude oil gathering pipelines are subject to common carrier regulation by FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain tariffs on file with FERC setting forth the rates we charge for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that our rates must be “just and reasonable” and that we provide service in a manner that is nondiscriminatory. Shippers on our crude oil gathering pipelines may protest our tariff filings, file complaints against our existing rates, or FERC can investigate our rates on its own initiative. In the event that FERC finds that our existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was enacted, which reduced the highest marginal United States federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. In a series of related issuances on March 15, 2018, the FERC revised its policy so that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates, and proposed rules for implementing this revised policy and the corporate income tax rate reduction pursuant to the Tax Cuts and Jobs Act of 2017 with respect to natural gas pipeline rates. The proposed rules, if they become final, would require all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time filing providing certain financial information that will allow the FERC and other stakeholders to evaluate the impacts of the revised policy and the corporate income tax rate reduction on each individual pipeline's rates, and to select one of four options: file a limited NGA Section 4 filing reducing its rates only as required related to the revised policy and the Tax Cuts and Jobs Act of 2017, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. Please read "Item No. 2, Recent Developments—Interstate Natural Gas Transportation Regulation".

The FERC's Revised Policy Statement requires the reduced maximum corporate tax rate to be reflected in initial oil cost-of-service rates and cost-of-service rate changes going forward and in future filings of Page 700 of FERC Form No. 6. FERC will consider the information provided by pipelines in Page 700 of FERC Form No. 6 in its 2020 five-year review of the oil pipeline index level. Please read "Item No. 2, Recent Developments—Interstate Natural Gas Transportation Regulation".

We cannot predict the outcome of the NOPR, but the cost of service rates we are permitted to charge our customers for transportation and storage services could be impacted when MRT, or if EGT, files a limited or general NGA Section 4 rate filing or if the FERC or customers challenge the cost-of-service rates that EGT is authorized to charge. We also cannot predict the outcome of the 2020 oil pipeline index five-year review, but the rates we are permitted to charge our customers for cost-of-service based crude oil transportation services could be impacted. If FERC requires us to establish new tariff rates for either our natural gas or crude oil pipelines that reflect a lower federal corporate income tax rate and the Revised Policy Statement, it is possible the rates would be reduced, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Item 5. Other Information

We are including information in this Part II. Item 5. in order to: (i) file Exhibit 99.1 hereto to replace in its entirety the section under the heading "Material U.S. Federal Income Tax Considerations" that appears in (a) the prospectus supplement we filed with the SEC on May 12, 2017 (the "ATM Prospectus") and (b) the Registration Statement on Form S-3 (Registration File No. 333-212192) we filed with the SEC on June 23, 2016 (the "DRIP Registration Statement"), to provide updated disclosure regarding the material tax considerations associated with our operations and the purchase, ownership and disposition of our common units and (ii) provide the legal opinion of Vinson & Elkins L.L.P. relating to certain tax matters in connection with the ATM Prospectus and the DRIP Registration Statement, a copy of which is filed as Exhibit 8.1 hereto.

Item 6. Exhibits

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Management contracts and compensatory plans and arrangements are designated by a star (*).

Agreements included as exhibits are included only to provide information to investors regarding their terms. Agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and no such agreement should be relied upon as constituting or providing any factual disclosures about Enable Midstream

Partners, LP, any other persons, any state of affairs or other matters.

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2.1	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192545	Exhibit 2.1
3.1	Certificate of Limited Partnership of CenterPoint Energy Field Services LP, as amended	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192545	Exhibit 3.1
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant's Form 8-K filed November 15, 2017	File No. 001-36413	Exhibit 3.1
4.1	Specimen Unit Certificate representing common units (included with Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP as Exhibit A thereto)	Registrant's Form 8-K filed April 22, 2014	File No. 001-36413	Exhibit 3.1
4.2	Indenture, dated as of May 27, 2014, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.1
4.3	First Supplemental Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.2
4.4	Registration Rights Agreement, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.3
4.5	Registration Rights Agreement, dated as of February 18, 2016, by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc.	Registrant's Form 8-K filed February 19, 2016	File No. 001-36413	Exhibit 4.1
4.6	Second Supplemental Indenture, dated as of March 9, 2017, by and among Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed March 9, 2017	File No. 001-36413	Exhibit 4.2
+8.1	Opinion of Vinson & Elkins L.L.P. relating to tax matters.			
+31.1	Rule 13a-14(a)/15d-14(a) Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
+32.1	Section 1350 Certification of principal executive officer			
+32.2	Section 1350 Certification of principal financial officer			

+99.1	Material U.S. Federal Income Tax Considerations
+101.INS	XBRL Instance Document.
+101.SCH	XBRL Taxonomy Schema Document.
+101.PRE	XBRL Taxonomy Presentation Linkbase Document.
+101.LAB	XBRL Taxonomy Label Linkbase Document.
+101.CAL	XBRL Taxonomy Calculation Linkbase Document.
+101.DEF	XBRL Definition Linkbase Document.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENABLE MIDSTREAM PARTNERS, LP
(Registrant)

By: ENABLE GP, LLC
Its general partner

Date:	May 2, 2018	By:	/s/ Tom Levescy
			Tom Levescy
			Senior Vice President, Chief Accounting Officer and Controller
			(Principal Accounting Officer)